2021-22 AEMO Budget and Fees

Introduction

This document sets out AEMO's budget and fees for 2021-22.

AEMO is an independent, not-for-profit public company limited by guarantee, owned jointly by energy industry members and the Commonwealth, New South Wales, Queensland, South Australian, Tasmanian, Victorian, Western Australian and Australian Capital Territory governments.

Our primary activity is the operation of Australia's energy systems and markets, balancing supply and demand in real time, to provide safe, reliable and affordable energy to all Australians. AEMO also has responsibility for planning functions in the NEM at the national and Victorian level, and various subsidiary functions directed by government legislation and regulations.

The accelerating pace of transformation and market reform in the sector has required AEMO to add new capabilities including specialist forecasting, planning, engineering, engagement, and technology skills required to deliver our obligations, and in turn adding to costs that need to be recovered.

As market participants grapple with the same complexity, AEMO is conscious that participants are facing increased costs and significant pressure on margins. Rising fees and charges for a number of AEMO's services reflect similar cost increases, particularly acquiring specialist skills, that have impacted participants.

The 2021-22 operating expenditure increase is largely the result of increasing capabilities to meet growth-related connections activity, and IT & Telecommunications and Depreciation & Amortisation expenditure associated with reform investment programs that are going live in the financial year. The 2021-22 capital expenditure program is $140.3 million of which an estimated $4.6 million will be funded through grant income, leaving a net capital expenditure program of $135.7 million to deliver market reforms, replace technology systems and integrate distributed energy systems into wholesale markets. NEM fees, are budgeted to increase by 8.3% for 2021-22.

Any level of cost escalation is challenging for industry participants. During 2020-21, AEMO initiated an organisational excellence program to achieve cost reductions and synergies. Savings of $10 million were achieved in 2020-21 and a similar magnitude is being targeted for 2021-22. For the coming year, AEMO has sought to limit fee increases to cover expenditure that is required to deliver core obligations, meet new obligations, and support critical reform programs, noting ongoing work to deliver additional savings in coming years.

During 2020-21 AEMO also initiated an uplift in market-facing engagement and transparency. For our budget, this has taken the form of an inaugural Financial Consultative Committee, where representatives from Energy Networks Australia, the Australian Energy Council, Clean Energy Council, Energy Consumers Australia, and government members were able to review and discuss AEMO's operational priorities and consequent budget imperatives. This initiative will be further developed in 2021-22.

In order to reduce the short-term impact of additional capital costs on participants, reliance on debt financing has increased to fund investments in foundational technology platforms, upgrade legacy technology systems and deliver mandated energy reform programs.

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1. Budget

To improve transparency and rigour of its budget and fee process and outcomes, AEMO established a Finance Consultation Committee consisting of a representative group of stakeholders that have reviewed and provided comment on a draft AEMO 2021-22 budget. Finance Consultation Committee discussions on the draft budget have been taken into consideration by the AEMO Board in approving the final 2021-22 Budget.

Only reform programs that are underway are captured in the 2021-22 investment program. Energy Security Board (ESB) post-2025 NEM reform projects are not captured in this Budget.

AEMO's reliance on debt funding in 2021-22 is $111 million, which takes the outstanding debt balance to $469 million at the end of the budget year. This total outstanding debt balance reflects funding of projects in progress and investments in service, as well as the accumulated operating deficit.

In July 2021, AEMO will publish its annual Corporate Plan that will detail the activities, priorities, and key performance indicators for AEMO for the financial year.

1.1 Profit and Loss Summary

Excluding the Victorian transmission network service provider (TNSP) function, AEMO's budgeted fees, tariffs and other revenues are $275.5 million for 2021-22 against operating expenditure of $277.9 million. The $2.4 million annual operating deficit for 2021-22 results in an estimated accumulated deficit at the end of the fiscal year of $57.0 million. Refer to Table 1 Summary profit and loss.

Table 1 Summary profit and loss

	AEMO (excl. Vic TNSP)			Victorian TNSP			AEMO		
	Budget 2020-21 $'m	Budget 2021-22 $'m	Variance $'m	Budget 2020-21 $'m	Budget 2021-22 $'m	Variance $'m	Budget 2020-21 $'m	Budget 2021-22 $'m	Variance $'m
Fees and Tariffs	205.8	255.0	49.2	-	-	-	205.8	255.0	49.2
TUoS Income	-	-	-	591.5	603.0	11.5	591.5	603.0	11.5
PCF Fees	1.0	1.0	-	-	-	-	1.0	1.0	-
Settlement Residue	-	(0.0)	(0.0)	52.0	43.5	(8.6)	52.0	43.4	(8.6)
Other Revenue	13.4	19.5	6.1	60.7	58.4	(2.2)	74.1	77.9	3.9
Network Charges	-	-	-	(669.9)	(678.7)	(8.8)	(669.9)	(678.7)	(8.8)
NET REVENUE	**220.2**	**275.5**	**55.3**	**34.3**	**26.2**	**(8.1)**	**254.5**	**301.7**	**47.2**
Labour	152.3	155.6	3.3	10.4	12.7	2.3	162.7	168.3	5.6
Consulting	12.9	10.8	(2.1)	11.6	10.2	(1.4)	24.6	21.1	(3.5)
IT & Telecommunications	33.3	47.3	14.1	0.0	0.0	(0.0)	33.3	47.4	14.1
Occupancy	8.2	7.7	(0.6)	-	-	-	8.2	7.7	(0.6)
Other Expenses	19.1	21.2	2.1	1.5	2.0	0.5	20.6	23.2	2.6
Depreciation and Amortisation	28.4	43.9	15.4	0.0	0.0	(0.0)	28.5	43.9	15.4
Financing Costs	1.4	2.1	0.7	-	-	-	1.4	2.1	0.7
Corporate Recovery (TNSP)	(7.5)	(10.7)	(3.2)	7.5	10.7	3.2	(0.0)	0.0	0.0
TOTAL OPERATING EXPENDITURE	**248.1**	**277.9**	**29.8**	**31.1**	**35.7**	**4.6**	**279.3**	**313.6**	**34.3**
ANNUAL SURPLUS / (DEFICIT)	**(28.0)**	**(2.4)**	**25.6**	**3.2**	**(9.5)**	**(12.7)**	**(24.8)**	**(11.9)**	**12.9**

1.1.1 Revenue

AEMO's Fees and Tariffs revenue is established to recover operating expenditure for each energy market it operates and the recovery of other services consistent with legislative authority. The $49.2m 2021-22 budget increase in Fees and Tariffs revenue reflects recovery of higher operating expenditure as compared to 2020-21 and the net movement in particular function over or under recoveries. Detail of each function's revenue requirement is presented in section 2 of this document.

Transmission Use of Systems (TUOS) income reflects revenue recovery for the provision of shared transmission network services to users of the Victorian Declared Transmission System (DTS) including the planning of future requirements and the procuring of augmentations in the DTS.

The increase of $11.5 million in TUOS income in 2021-22 reflects the recovery of the net increase in expenditure associated with regulated and non-regulated network charges, net inter-regional TUOS, settlement residue and AEMO's Vic Planning and NTP costs, partially offset by an decrease in the over recovery surplus. Refer to section 2.6 in this document for detail on the Victorian Transmission Network Service Provider revenue and fees.

AEMO's Other Revenue increase of $3.9m in the 2021-22 budget is due to a forecast increase in both Vic TNSP and NEM connections revenue partially offset by a reduction in Vic TNSP negotiated services income.

1.1.2 OPERATING EXPENDITURE

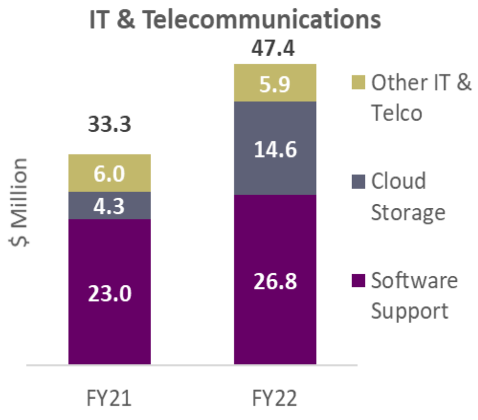
AEMO's total budget operating expenditure increases by $34.3million in 2021-22 as compared to the prior year budget. Key drivers of the increased expenditure include:

- NEM 5 Minute and Global Settlements (5MS) ($22.3m, 65%) and NEM Distributed Energy Resources (DER) ($2.3m, 7%) reform programs move from the project stage into the operational stage during 2021-22. As a result, the 5MS and DER functions will incur operating expenditure, including labour, cloud costs, and third-party IT support contracts. Further, recovery of the investment via depreciation commences and consistent with all operational functions, corporate overhead expenditure is budgeted against the 5MS and DER functions.
- Vic TNSP ($4.6m,13%) increased connections activity resulting in higher labour expenditure partially offset by a reduction in consulting, and an increased allocation of corporate overhead costs – due to corporate cost increases and an increase in the percentage allocation to Vic TNSP due to growth in this function.
- National Transmission Planner ($2.1m, 6%) reflecting higher net labour to deliver the actionable Integrated System Plan (ISP).
- NEM Connections ($3.7m, 11%) reflecting an increase in internal labour ($1.8m) and external contractor expense ($1.9m) to support an increase national connections volume and complexity.

The operating cost categories of expenditure experiencing the largest growth from the prior year are as follows:

IT & Telecommunications ($14.1m): The main drivers of increased IT & Telecommunications expenditure in the 2021-22 budget are as follows:

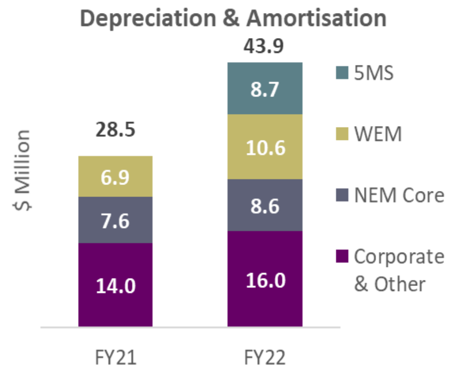
- Cloud costs ($10.3m): AEMO is transitioning from on premise storage of data to cloud storage arrangements. New IT infrastructure including the 5MS and DER programs are being developed using cloud storage arrangements. Of the $10.3m increase, a budget of $8.6m is allocated to 5MS.
- Software Support ($3.8m): Software support incorporates contract costs for business operational systems as well as technical infrastructure and operations, cyber and enterprise applications. AEMO's investment programs including energy transition reform programs such as 5MS, DER and WA reform, along with its cyber and digital uplift and enablement investments result in additional software support arrangements.



Depreciation & Amortisation ($15.4m): AEMO's depreciation and amortisation expense reflects the recovery of its investment in capital projects once they 'go live'. Assets associated with major energy reform programs in Western Australia and the NEM are progressively going live, as are assets associated with AEMO's digital investment program including replacement of legacy systems.

Key projects impacting the 2021-22 depreciation budget include:

- 5MS program, DER program, Operational Forecasting Program
- WEM: Market/Regulatory design and Technical/Process design, Reserve Capacity Mechanism, Constraint Management, Generator Performance Standards, DER, Power Systems Operations
- Digital: Corporate Cyber Privileged Access Management, Plexos Uplift, Public Cloud design/build, Delivery Centre and Application Simplification program, WEB Portal Refresh



Net Labour ($5.6m): 2021-22 budget labour expenditure increases are largely due to the following, noting that a portion of the total increase is offset through labour reductions delivered under the organisation transformation program:

- Employee cost escalation assumed at 2% ($3.3m)
- Increased NEM and VicTSNP connections reflecting volume and complexity of connections ($4.1m)
- National Transmission Planner roles to support delivery of the ISP ($0.9m)
- New roles relating to investment projects going into service including components of the 5MS, NEM DER and WA DER programs, and cyber risk management activities ($2.3m).

Refer to Appendix A for a detailed Consolidated Profit and Loss Statement.

1.2 Capital Expenditure Summary

AEMO's 2021-22 gross capital expenditure budget of $140.3 million is reduced by an estimated $4.6 million of grant funding, leaving a net capital expenditure program of $135.7 million. The capital spend is largely driven by the significant change the industry is going through, which has resulted in a need to refresh current systems and carry out large regulatory-directed programs.

AEMO's governance model results in initial funding of investments via an external debt facility, with the debt funding repaid as the assets are depreciated once in use and the depreciation is recovered from participants. AEMO's external debt facility to fund capital investments consists of a 3 year and a 5-year tranche that total $485 million.

During 2020-21 an external review of the Digital Platform, System and Cyber Uplift and Lifecycle renewals program was undertaken. The review largely endorsed the timing, cost, and benefits of the program, however recommendations for the deferral of some investments were supported by AEMO and the program has been adjusted accordingly.

Table 2 provides a summary of the 2021-22 net capital expenditure budget categories.

Table 2 Capital program summary

Net Capital Expenditure ($'m)	2020-21 and prior	Budget 2021-22
Digital Platform, System and Cyber Uplift and lifecycle renewals	172.6	51.1
DER Integration	35.2	13.6
Regulatory Compliance Programs	111.9	71.0
Net Capital Expenditure	319.7	135.7

AEMO's capital program can be broadly grouped into three categories:

- Digital Platform, System and Cyber Refresh and Lifecycle Renewals
  - A high proportion of AEMO's systems are bespoke and are at, or nearing end of life and need to be replaced. AEMO has commenced a significant refresh of its systems that includes the development of a modern digital platform that will provide more reliable and transparent data. The timing of system replacement / upgrades where possible has been aligned to the implementation of reform programs to lower the overall cost of delivery.
  - Security of AEMO's systems is critical to its ability to maintain operations, and as such AEMO's cyber risk reduction programs include threat and vulnerability management, threat detection and response, and identify access management.
  - The significant increase in data volumes necessitates an increase in computational capability, analytics, design, and digitalisation to support the real-time operation of AEMO's energy systems and markets.
- DER Integration
  - AEMO is working in partnership with the ESB, market bodies, and stakeholders to design and implement technical integration of DER.
  - In Western Australia, AEMO is collaborating with Western Power, Synergy, and other stakeholders to deliver the WA Government's Energy Transformation Taskforce's DER Roadmap integration of DER into the Wholesale Electricity Market and the South West Interconnected System.
- Regulatory Compliance Programs
  - 5MS – the program to move from a 30-minute settlement period to a 5-minute settlement period is planned to go live on 1 October 2021. The dispatch and settlements components of the program go live earlier in 2021-22.
  - WA Market Reform – AEMO continues to support the WA Government's Foundational Regulatory Frameworks including the planning and implementation of a new market design.
  - Wholesale Demand Response – this program will implement a mechanism for third party demand response service providers to participate in the wholesale energy market.

2. Fees

AEMO's annual revenue requirement, as reflected in its budget, is established to recover operating expenditure for each energy market it operates and the recovery of other services consistent with legislative authority.

Operating on a 'fee for service' and cost recovery basis, the revenue requirement is recovered through fees and charges levied to participants. Each fee is limited to recovering the costs of providing that particular service. In any year, the revenues collected, and costs incurred, may vary from the levels that were estimated in the budget and reflected in fees. Therefore, the financial budget in a year may include prior year over or under recoveries to adjust for these variances – with the variances referred to as a surplus or deficit.

In Western Australia AEMO's allowable revenue requirement is approved by the Economic Regulation Authority every three years.

In March 2021, informed by stakeholder feedback and internal analysis, AEMO published its:

- Electricity Fees Structures determination detailing the structure of the Participant fees to apply from 1 July 2021 under the National Electricity Rules (NER); and
- Determination regarding the fee structures to apply to gas participant fees from 1 July 2021, having regard to the fee structure principles and National Gas Objective (NGO).

These determinations detail the fee structures to recover AEMO's applicable budget revenue requirements.

This section presents the revenue requirement and fees that will apply from 1 July 2021 for each function.

2.1 National Electricity Market

Purpose of this function

Power system security and reliability

Market operations and systems

Wholesale metering, settlements and prudential supervision

Longer-term energy forecasting and planning services

(For the eastern and southern Australian states)

Revenue requirement and fees

The benchmark NEM fee for 2021-22 is $0.59/MWh (+8.3% on 2020-21).

Table 3 NEM revenue requirement and indicative benchmark fee

	Budget 2020-21	Budget 2021-22	Variance	Variance
NEM Revenue Requirement ($m)	95.7	103.0	7.3	7.6%
Forecast Consumption (MWh)	176,391	175,365	-1,026	-0.6%
NEM Benchmark Fee ($/MWh)	0.54	0.59	0.04	8.3%

Refer to table 28 for the components of the NEM fee.

The NEM revenue requirement increase of $7.3m reflects:

- increased operating expenditure of $4.4m due to $2.5m increased labour expenditure (wage escalation and incremental NEM connections roles) and $1.9m non-labour related expenditure (depreciation & amortisation, IT cloud costs and software support contracts, insurance and finance charges); and
- increased revenue of $2.9m to reduce the annual NEM operating deficit (under-recovery) to $11m for 2021-22. NEM has been under recovering its operating

expenditure in recent years resulting in a forecast accumulated operating deficit of approx. $80m at the end of 2020-21.

The NEM benchmark fee increase of 8.3% is higher than the 7.6% revenue requirement increase, due to the 2021-22 impact of the lower MWh forecast consumption.

The consumption forecast decline in 2021-22 compared with the prior year budget, reflects the combined impacts of weather modelling, household renewable generation and storage, and COVID-19 assumptions.

2.2 Full Retail Contestability (FRC) Electricity

Purpose of this function

To facilitate retail market competition in the east coast and southern states of Australia by managing and supporting:

- Data for settlement purposes
- Customer transfers
- Business to business processes
- Market procedure changes

Revenue requirement and fees

The FRC Electricity fee for 2021-22 is $0.02592 per connection point per week (+1.7%).

Table 4 FRC revenue requirement and fee

	Budget 2020-21	Budget 2021-22	Variance	Variance
FRC Revenue Requirement ($m)	13.8	14.2	0.4	2.7%
Connection Points (Million)	10.4	10.5	0.1	1.2%
FRC Fees ($ per connection point per week)	0.02550	0.02592	0.00042	1.7%

The FRC revenue requirement increase of $0.4m reflects:

- increased operating expenditure of $0.9m largely due to wage escalation; partially offset by
- a prior year revenue over-recovery returned to consumers.

The 1.7% FRC Fee increase reflects the $14.2m budget revenue requirement being passed through to 10.5 million connection points. The 0.1m increase in forecast connection points reduces the impact of the percentage fee increase per connection.

2.3 5MS/GS Compliance (5MS) and IT Upgrade

Purpose of this function

From 1 July 2021 a new fee category of "5MS/GS Compliance and IT Upgrade" will be applied to recover the consolidated costs of the Five-Minute and Global Settlement rule changes and upgrades to related legacy IT systems for the National Electricity Market.

Revenue requirement and fees

The benchmark 5MS fee for 2021-22 is $0.14/MWh.

Table 5 5MS revenue requirement and fee

	Budget 2020-21	Budget 2021-22	Variance	Variance
5MS Revenue Requirement ($m)	-	24.8	24.8	-
Consumption (MWh)	176,391	175,365	-1,025.6	-0.6%
5MS Benchmark Fee ($/MWh)	-	**0.14**	**0.14**	-

The 2021-22 5MS revenue requirement of $24.8m reflects:

- operating expenditure of $22.3m consisting of labour ($1.6m), consulting ($0.8m), IT & telecommunications ($9.5m), depreciation & amortisation ($8.8m) and other expenses ($1.6m); and
- a forecast over-recovery of $2.5m. As the 5MS program is going live during the 2021-22 year, the 2021-22 Budget does not reflect a full year of operating expenditure. As a result, the operating expenditure is expected to be higher in future years and to smooth pricing as the systems are introduced, an over-recovery has been factored into the first year of the program. It is anticipated that future year fee increases will reflect wage and CPI escalation only.

The $0.14 5MS Benchmark Fee reflects the 2021-22 budget revenue requirement being passed through to NEM participants.

Refer to table 28 for the components of the 5MS fee.

2.4 Distributed Energy Resources Integration Program (DER)

Purpose of this function

From 1 July 2021 a new fee category will be applied to recover the consolidated costs of the Integration of DER into the National Electricity Market.

Revenue requirement and fees

The benchmark DER fee for 2021-22 is $0.03/MWh.

Table 6 DER revenue requirement

	Budget 2020-21	Budget 2021-22	Variance	Variance
DER Revenue Requirement	-	5.7	5.7	-
Consumption (MWh)	176,391	175,365	-1,025.6	-0.6%
DER Benchmark Fee ($/MWh)	-	**0.03**	**0.03**	-

The DER revenue requirement of $5.7m reflects:

- operating expenditure of $2.3m consisting of labour ($0.6m), depreciation & amortisation ($0.9m) and prior year asset write off ($0.8m); and
- a forecast budget over-recovery of $3.4m. As the DER program is going live during the 2021-22 year, the 2021-22 Budget does not reflect a full year of operating expenditure. As a result, the operating expenditure is expected to be higher in future years and to smooth pricing as the systems are introduced, an over-recovery has been factored into the first year of the program. It is anticipated that future year fee increases will be minimal.

The $0.03 DER Benchmark Fee reflects the revenue requirement being passed through to NEM participants.

Refer to table 28 for the components of the DER fee.

2.5 National Transmission Planner (NTP)

Purpose of this function	Delivering an actionable Integrated System Plan (ISP).

Revenue requirement

The 2021-22 NTP revenue requirement reflects a 15.6% increase on the 2020-21 Budget.

Table 7 National Transmission Planner revenue requirement

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue requirement	$19.9m	$23.0m	$3.1m	15.6%

The NTP revenue requirement increase of $3.1m reflects:

- increased operating expenditure of $2.1m due to higher net labour and consulting reflecting incremental cost associated with delivering the ISP; and
- net $1.0m year-on-year increase in the deficit recovery (2021-22 budget gross deficit recovery of $5.4m due to the under recovery associated with the transitional rule change).

The 2021-22 final budget operating expenditure is $1.8m higher than the estimated cost to operate the NTP function detailed in the National Transmission Planner Charges Publication Notice, February 2021.

2.6 Victorian Transmission Network Service Provider (TNSP)

Purpose of this function	The provision of shared transmission network services to users of the Victorian Declared Transmission System (DTS) including the planning of future requirements and procuring of augmentations in the DTS.

Revenue requirement

TNSP Transmission Use of Systems (TUOS) fees are predominately influenced by network charges billed by the Victorian electricity transmission network owners and by estimates of settlement residue receipts.

The 2021-22 TUoS charges revenue requirement is $603m reflecting a 1.9% increase on the 2020-21 Budget.

Table 8 National Transmission Planner revenue requirement and operating costs

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue requirement	$591.5m	$603.0m	$11.5m	1.9%

The TUoS revenue requirement increase of $11.5m largely reflects:

- a net $10.0m increase in transmission easement tax and Victorian Government System Integrity Protection Scheme project costs, partially offset by reduced costs relating to the procurement of Western Murray System Strength Remediation services and a lower AusNet Services regulated assets revenue requirement;
- a net $15.3m increase in the charge to the Victorian jurisdiction for the use of the network in other jurisdictions, lower estimated Settlement Residue Auction proceeds, and lower settlement residue income for the Victorian region as a result of lower estimated spot prices; and
- an offsetting return of the estimated $13.8m 2020-21 over recovery and lower AEMO National Transmission Planner (NTP) costs.

2.7 Western Australia Wholesale Electricity Market (WEM)

Purpose of this function

Power system security and reliability

Market operations and systems

Wholesale metering, settlements, and prudential supervision

Preparing for and implementing the WA Government's WEM and Constrained Access Reforms

Longer-term energy forecasting and planning services

Revenue requirement and fees

The current WEM indicative benchmark fee is $0.894/MWh. This fee remains at $0.894/MWh in 2021-22.

Table 9 WEM revenue requirement and Fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)	31.7	30.8	-0.9	-2.8%
Energy consumption (GWh)	17,589	17,078	-511	-2.9%
	WEM Fees			
WEM Market Operator fee ($/MWh)	0.380	0.380	0.000	0.0%
WEM System Management fee ($/MWh)	0.514	0.514	0.000	0.0%
WEM fee ($/MWh)	0.894	0.894	0.000	0.0%
WEM fee (indicative benchmark) * ($/MWh)	1.788	1.788	0.000	0.0%

* The fee listed above is a benchmark fee calculated by dividing the total cost of the WEM functions by the total forecast consumption. The actual fee charged to both Market Customers and Generators is $0.380/MWh and 0.514/MWh for the Market Operations and System Management functions respectively.

The decrease in the WEM Revenue Requirement of $0.9m largely reflects the net of:

- a $2.9m return of over recovered funds; partially offset by
- increased operating expenditure in the 2021-22 budget of $2.0m consisting of depreciation & amortisation ($2.8m), net labour and consulting ($0.5m), partially offset by lower IT & telecommunications ($0.7m) and other expenses ($0.6m).

WEM energy consumption is estimated to decline by 2.9% in 2021-22 due to the combined impacts COVID-19, continued increases in rooftop PV, and lower industrial load forecast.

Other notes

The current three-year ERA determination on AEMO's allowable revenue and capital expenditure covers the period from 1 July 2019 to 30 June 2022.

2.8 Declared Wholesale Gas Market (DWGM)

Purpose of this function

To enable competitive dynamic trading based on injections and withdrawals from the transmission system that links producers, major users and retailers

This market provides the following broad services:

- Gas system security, market operations and systems
- Gas system reliability and planning
- Wholesale metering and settlements
- Prudential management

Revenue requirement and fees

The 2021-22 DWGM revenue requirement is $24.5m reflecting a $3.0m (13.9%) increase on the 2020-21 Budget.

Table 10 DWGM revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)	21.6	**24.5**	3.0	13.9%
Gas consumption (GJ)	231,200	**239,675**	8,475	3.7%
DWGM Variable Fees				
Energy tariff ($/GJ)	0.08887	0.09938	0.0	11.8%
Distribution Meter ($/day per meter)	1.28580	1.56470	0	21.7%
PCF Fee ($/GJ)	0	0	0.0	0.0%
Initial Registration Fees ($ / registration)				
Market Participant - Retailer	-	20,570	20,570	-
Market Participant - Trader	-	20,570	20,570	-
Market Participant - Distribution Customer	-	19,970	19,970	-

The DWGM revenue requirement increase of $3.0m largely reflects:

- increased operating expenditure in the 2021-22 Budget of approximately $3.1m consisting of depreciation & amortisation ($0.2m), IT & telecommunications ($0.6m), indirect enterprise recoveries ($1.3m) and other expenses ($1.0m) reflecting a provision for reserve gas supply in 2021-22.

Energy tariff

The energy tariff fee is to increase by 11.8% to $0.09938/GJ in 2021-22 reflecting the increase in the revenue requirement, partially offset by higher energy consumption of 3.7% in 2021-22.

Distribution meter fee

The distribution meter fee is paid by each market participant connected to a Declared Distribution System, or whose customers are connected to a Declared Distribution System, at a connection point which there is an interval metering installation.

The distribution meter fee relates to metering data services and is to increase by 21.7% to $1.56470 per meter per day in 2021-22.

Participant Compensation Fund (PCF) fee is not required to be charged in 2021-22, as the current level of DWGM PCF funds being held meets the Rules requirement.

Initial Registration Fees

As detailed in the gas fees determination published in March 2021, AEMO has determined to change registration fees commencing from 1 July 2021 as follows:

- introduce registration fees into wholesale gas markets, being the DWGM and STTM; and
- disaggregate by registerable capacity across any market in which registration fees apply.

DWGM Energy Consumption

The budgeted consumption for 2021-22 is based on data used in the March 2021 Gas Statement of Opportunities (GSOO) updated to reflect the current outlook.

Table 11 DWGM energy consumption

TJ	Budget 2020-21	Forecast* 2020-21	Budget 2021-22
Domestic	127,993	130,692	133,135
Industrial	65,745	64,679	63,090
Export	22,909	41,386	40,517
GPG	14,553	5,498	2,933
Total	231,200	242,255	239,675
		+4.8%	+3.7%

* Forecast annual 2020-21 consumption at June 2021.

2.9 Short Term Trading Market (STTM)

Purpose of this function

To enable a wholesale market gas balancing mechanism at the gas hubs – Sydney, Adelaide and Brisbane. The STTM function provides the following broad services:

- Market operations and systems
- Market Operator Service (MOS) – recovery of the pipeline operators' service costs in relation to the STTM and recovers this from participants
- Wholesale metering and settlements
- Prudential management

Revenue requirement and fees

The current STTM fee of $0.03684/GJ is to increase by 2.1% to $0.03762/GJ in 2021-22.

Table 12 STTM revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)	5.1	**5.4**	0.2	4.4%
Gas consumption (GJ)	139,479	**145,642**	6,163	4.4%
STTM Variable Fees				
Activity Fee ($/GJ withdrawn)	0.03684	0.03762	0.00078	2.1%
PCF Fee – Syd ($/GJ withdrawn per hub per ABN)	0	0	0	0.0%
PCF Fee – Adel ($/GJ withdrawn per hub per ABN)	0	0	0	0.0%
PCF Fee – Bris ($/GJ withdrawn per hub per ABN)	0	0	0	0.0%
Initial Registration Fees ($/Registration)				
STTM User (BRI, ADL, SYD hubs)	-	20,870	20,870	-
STTM Shipper (BRI, ADL, SYD hubs)	-	20,870	20,870	-
STTM Allocation Agent	-	16,970	16,970	-
STTM Pipeline Operator	-	36,470	36,470	-
STTM Distributor	-	36,170	36,170	-
STTM Storage facility Operator	-	36,470	36,470	-
STTM Production Facility Operator	-	36,470	36,470	-

The revenue requirement increase of $0.2m (4.4%) largely reflects an increase in IT corporate costs. The 2.1% STTM activity fee increase reflects the increase in the revenue requirement, partially offset by the higher energy forecast consumption in the budget year.

The STTM energy consumption forecast is based on data used in the March 2021 GSOO, updated to reflect the current outlook.

Table 13 STTM energy consumption

TJ	Budget 2020-21	Forecast* 2020-21	Budget 2021-22
Adelaide	20,327	21,002	21,426
Brisbane	31,173	37,961	33,511
Sydney	87,979	92,680	90,705
Total	139,479	151,643	145,642
		+8.7%	+4.4%

* Forecast annual 2020-21 consumption at June 2021.

The Participant Compensation Fund fee is not required to be charged in 2021-22, as the current level of STTM PCF funds being held meets the Rules requirement.

Initial Registration Fees
AEMO has determined to introduce initial registration fees for new STTM registered market participant commencing 1 July 2021. Registration fees have been based on effort associated with registration activities across the business.

2.10 FRC Gas Markets

Purpose of these functions

To provide the services and infrastructure to allow gas consumers to choose their retailer while also providing the business to business interactions to support efficient operation of the market.

The following broad services are provided:

- Support retail market functions and customer transfers
- Manage data for settlement purposes
- Implement market procedure changes
- Operate the central IT systems that facilitate retail market services

(Operated in Victoria, Queensland, South Australia, New South Wales and Western Australia)

2.10.1 Victorian FRC Gas

Revenue requirement and fees

The revenue requirement is little changed year on year.

The current Victorian FRC Gas fee is $0.06221 per customer supply point/month. As a result of the 2021-22 Budget increase in customer supply points the fee is to decrease to $0.05965 (down 4.1%) in 2021-22.

Registration fees applicable to Victorian FRC Gas have been disaggregated and increased in line with general cost increases and inflation.

Table 14 Vic FRC gas revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)	1.73	**1.74**	0.01	0.6%
Monthly average customer Supply points (Million)	2.21	**2.26**	0.04	2.0%
Vic Gas Fees				
FRC Gas Tariff ($ per customer supply point per month)	0.06221	0.05965	0.0	-4.1%
Initial Registration Fee ($ per participant retailer)	19,570	20,157	587.1	3.0%
Initial Registration Fee ($ per non-retailer participant)	19,570	20,157	587.1	3.0%

2.10.2 Queensland FRC Gas

Revenue requirement and fees

The 2021-22 revenue requirement has declined due to a reduction in labour costs.

The current Queensland FRC Gas fee is $0.26441 per customer supply point/month. This fee is to decrease to $0.26374 in 2021-22.

Registration fees applicable to Queensland FRC Gas have been disaggregated and increased in line with general cost increases and inflation.

Table 15 **Qld FRC gas revenue requirement and fees**

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)	0.79	**0.75**	-0.04	-5.1%
Monthly average customer Supply points (Million)	0.23	**0.23**	0.00	2.0%
Qld Gas Fees				
FRC fee ($ per customer supply point per month)	0.26441	0.26374	-0.00067	-0.3%
Registration Fee ($ per participant retailer)	17,510	18,035	525	3.0%
Registration Fee ($ per non-retailer participant)	17,510	18,035	525	3.0%

2.10.3 South Australia FRC Gas

Revenue requirement and fees

The revenue requirement has increase 2.8% due mainly to labour and IT systems expenditure.

The current South Australian FRC Gas fee is $0.20214 per customer supply point/month. This fee is to increase to $0.20341 (up 0.6%) in 2021-22.

Registration fees applicable to South Australian FRC Gas have been disaggregated and increased in line with general cost increases and inflation.

Table 16 **SA FRC gas revenue requirement and fees**

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)	1.2	**1.3**	0.0	2.8%
Monthly average customer Supply points (Million)	0.48	**0.49**	0.010	2.0%
SA Gas Fees				
FRC fee ($ per customer supply point per month)	0.20214	0.20341	0.00127	0.6%
Registration Fee ($ per participant retailer)	16,480	16,974	494	3.0%
Registration Fee ($ per non-retailer participant)	16,480	16,974	494	3.0%

2.10.4 New South Wales FRC Gas

Revenue requirement and fees

The revenue requirement is little changed year on year. A decline in depreciation and amortisation off-set by increased labour and other expenditure.

The current New South Wales (including Australian Capital Territory) FRC Gas fee is $0.14040 per customer supply point/month. This fee is to decrease to $0.13773 (down 1.9%), offsetting the budgeted growth in the number of customer supply points.

Table 17 NSW FRC gas revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)	2.9	**2.9**	0.0	0.1%
Monthly average customer Supply points (Million)	1.72	**1.75**	0.034	2.0%
NSW Gas Fees				
FRC fee ($ per customer supply point per month)	0.14040	0.13773	-0.00267	-1.9%
Registration Fee ($ per participant retailer)	-	20,157	20157	-
Registration Fee ($ per non-retailer participant)	-	20,357	20357	-

2.10.5 Western Australia FRC Gas

Revenue requirement and fees

The revenue requirement is budgeted to increase by 4% due to increased labour and IT system costs, partially offset by a reduction depreciation and amortisation, and a progressive return of accumulated surplus to members.

The fee for 2021-22 is to decrease by 1.6% to $0.11974.

Table 18 Western Australia FRC gas revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)	1.35	**1.40**	0.1	4.0%
Fees				
FRC fee ($ per customer supply point per month)	0.12170	0.11974	-0.00196	-1.6%
Initial Registration Fee – member	13,435	13,565	130	1.0%
Initial Registration Fee – associate member	2,686	2,712	26	1.0%
Annual Fee – Member	20,649	20,849	200	1.0%
Annual Fee – Associated Member	4,027	4,066	39	1.0%

Note: associate members are self-contracting users that are party to the WA Gas Retail Market Agreement. The 2021-22 registration and annual fees are calculated according to clause 362A(5) of the Retail Market Procedures (WA).

2.11 Eastern and South Eastern Gas Statement of Opportunity (GSOO)

Purpose of this function	To report the supply adequacy of eastern and south-eastern Australian gas markets to meet energy needs – AEMO reports on demand and supply, and delivery constraints projected for the next 20 years Retailers across the FRC gas market jurisdictions are currently charged for GSOO costs at a flat rate per customer supply point

Revenue requirement and fees

Commencing 1 July 2021, the recovery of AEMO's GSOO revenue requirement will be recovered:

- 30% from producers on a $/GJ produced basis (inclusive of LNG imports); and
- 70% from retailers on a $/ supply point basis.

The 2021-22 fee is $0.00030871 per GJ for producers and $0.02669 per customer supply point for retailers.

Table 19 GSOO revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)	2.2	**2.2**	0.0	-0.1%
Gas Producers Production (PJ)	2,034	**2,063**	29.0	1.4%
Monthly Average Customer Supply Points (Millions)	4.75	**4.73**	0.00	-0.4%
Fees				
Producer fee ($ per GJ)		0.00030871	0.00030871	
Retailer fee ($ per customer supply point)	0.03869	0.02669	-0.012	-31.0%

2.12 Gas Supply Hub (GSH)

Purpose of this function	To provide an exchange for the wholesale trading of natural gas to enable improved wholesale trading for an east coast gas market affected by significant liquefied natural gas (LNG) exports in Queensland – through an electronic platform, GSH participants can trade standardised, short-term physical gas products at each of the three foundation pipelines connecting at Wallumbilla AEMO centrally settles transactions, manages prudential requirements and provides reports to assist participants in managing their portfolio and gas delivery obligations
Revenue requirement and fees	Fees are determined outside of AEMO's budget and fee setting process and are set within the Gas Supply Hub exchange agreement with changes made in consultation with stakeholders. The GSH fee schedule is included in this report for information purposes.

Table 20 GSH revenue requirement and fees

	Fee type	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement ($m)		1.4	**1.3**	-0.1	-6.8%
Gas consumption (GJ)		139,479	**145,642**	6,163	4.4%
Fees					
Trading participants	Fixed Fee - one licence per annum	12,000	12,000	0	0.0%
	Fixed Fee - additional licence per annum	12,000	12,000	0	0.0%
	Variable transaction fee				
	• Daily product fee ($/GJ)	0.03	0.03	0.00	0.0%
	• Weekly product fee ($/GJ)	0.02	0.02	0.00	0.0%
	• Monthly product fee ($/GJ)	0.01	0.01	0.00	0.0%
Reallocation participants	Fixed fee per annum	9,000	9,000	0	0.0%
Viewing participants	Fixed fee per annum	3,600	3,600	0	0.0%

2.13 Gas Capacity Trading (CTP)

Purpose of this function

To facilitate the secondary trading of pipeline capacity.

The following broad services are provided:

- Settlement and prudential management of capacity transactions.
- Exchange transaction information with facility operators to facilitate the delivery of capacity transactions.
- Update STTM contract rights and DWGM accreditations in accordance with transactions in integrated products.

Revenue requirement and fees

There is no change to current fixed fees for 2021-22.

Effective from 1 July 2021, AEMO has determined to disaggregate compression service fees from other transportation services traded on the CTP, and will continue to apply charges on a $/GJ basis.

To encourage participation and increased liquidity in the market, the 2021-22 CTP fees for both compression and other transportation are set at $0.008, including $0.00318 relating to OTS code panel.

Table 21 CTP revenue requirement and fees

	Fee type	Budget 2020-21	Budget 2021-22	Variance	Variance
Capacity Trading Platform (CTP)	Fixed Fee - one licence per annum (commodity & capacity)	12,000	12,000	0	0%
	Fixed Fee - one licence per annum (capacity only)	7,000	7,000	0	0%
	Variable transaction fee				
	• Daily product fee ($/GJ)	0.045		-0.045	-
	• Weekly product fee ($/GJ)	0.035		-0.035	-
	• Monthly product fee ($/GJ)	0.025		-0.025	-
	• Variable transportation fee ($/GJ) Daily/Weekly/Monthly	-	0.008	0.008	-
	• Variable compression fee ($/GJ) Daily/ Weekly/ Monthly	-	0.008	0.008	-
	Initial Registration Fee - Part 24 Facility Operators ($ per participant)	15,450	15,914	464	3.0%

Note: the variable transaction fees for CTP are including a fee of $0.00318 relating to OTS code panel.

2.14 Day Ahead Auction (DAA)

Purpose of this function

To reallocate contracted but unnominated transportation capacity to shippers that value it the most

The following broad services are provided:

- Auction platform to allocate capacity to shippers
- Settlement and prudential management of auction transactions
- Provide auction results to facility operators to facilitate the delivery of auction transactions
- Update DWGM accreditations in accordance with transactions to a DWGM interface point

Revenue requirement and fees

The DAA revenue requirement is budgeted to increase $0.1m (7.8%), reflecting higher than budgeted labour and corporate cost in 2020-21. Gas consumption growth provides scope for fee increases less than the increase in the revenue requirement.

From FY2021-22 two variable fees apply:

- Other transport fees of 0.036 ($/GJ) which have increased 3% compared with the current variable fee
- Compression fee of 0.28 ($/GJ), which is 20% lower than the current variable fee.

Table 22 DAA revenue requirement and fees

	Fee type	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement		1.3	**1.4**	0.1	7.8%
Gas Consumption (DAA) (GJ)		39,572,500	**42,129,000**	2,556,500	6.5%
Fees					
Day ahead Auction (DAA)	Other transportation fee ($/GJ)	0.035	0.036	0.001	3.0%
	Compression fee ($/GJ)	0.035	0.028	-0.007	-19.5%
	Initial Registration Fee - Auction participants ($ per participant)	15,450	15,914	464	3.0%

Note: the variable fee for DAA is including a fee of $0.00318 relating to OTS code panel.

2.15 Operational Transportation Service (OTS) Code Panel

Purpose of this function

To assess and consult on proposals to amend the Operational Transportation Service Code and develop proposals to amend the Code, prepare impact and implementation reports on proposals, make recommendations in relation to proposals, report to the AER on proposals, develop proposals at the request of the AER and other related functions

Revenue requirement and fees

OTS Code Panel revenue requirement is budgeted to increase 3% due mainly to cost escalation. The fee of $0.00318 per GJ is levied on all CTP and DAA trades.

Table 23 OTS Code Panel revenue requirement and fee

	Budget 2020-21	Budget 2021-22	Variance	Variance
OTS Code Panel Revenue Requirement	0.12	**0.13**	0.00	3.0%
OTS Code Panel ($/GJ)	0.00309	0.00318	0.00009	3.0%

Other notes

AEMO is permitted to recover costs incurred in relation to the OTS Code Panel including establishing and operating the OTS Code Panel, the participation of the AEMO member on the OTS Code Panel and providing services to facilitate the functioning of the OTS Code Panel.

2.16 Gas Bulletin Board (GBB)

Purpose of this function

To provide information relating to gas production, transmission, storage, and usage for facilities that are connected to the east coast gas market

GBB provides market participants timely data to assist in decision making. This includes capacity outlooks, nominations and forecasts, actual flows, line pack adequacy and additional information for maintenance planning

Revenue requirement and fees

The revenue requirement has increased in 2021-22 due to under recovery in 2020-21 and escalation of labour costs.

Fees have been increased 2.2% to $0.00049/GJ for Producers and $0.00245/GJ for Participants in Wholesale Gas Markets.

Table 24 GBB revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
Revenue Requirement	1.87	**1.96**	0.1	4.6%
Gas Producers Production (PJ)	2,034	**2,063**	29	1.4%
Fees				
Producer ($/GJ)	0.00048	0.00049	0.000	2.2%
Participants in Wholesale Gas Market ($/GJ)	0.00244	0.00249	0.000	2.2%

2.17 Western Australian Gas Services Information (GSI)

Purpose of this function

To ensure:

- Security, reliability and availability of the supply of natural gas
- Efficient operation and use of natural gas services
- Efficient investment in natural gas services
- Facilitation of competition in the use of natural gas services

The GSI function includes the GBB [WA] and WA GSOO:

- Similar to the GBB on the East Coast, the WA GBB is an information website hub to provide flow information on gas, transmission, storage, emergency management with supply disruptions, and demand in WA
- The WA GSOO is an annual planning document providing medium to long-term outlook of WA gas supply and demand and transmission and storage capacity.

Revenue requirement and fees

The GSI recovery is to increase to $1.752 in 2021-22 from $1.115m in 2020-21, as the 2020-21 Revenue Requirement included a return of surplus funds of $0.7m which isn't applicable in 2021-22. Excluding the surplus return there is a slight decline in the 2021-22 budgeted revenue requirement.

Table 25 GSI revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
AEMO GSI revenue requirement	1.11	1.75	0.6	57.2%

Other notes

The current three-year ERA determination on AEMO's allowable revenue and capital expenditure covers the period from 1 July 2019 to 30 June 2022.

2.18 Other budgeted revenue requirements

Purpose of this function

AEMO also collects revenue to recover the costs of the following functions.

- The SA planning function expenditure is budgeted to remain stable in FY22
- Expenses associated with administration of the Settlement Residue Auction (SRA) are recovered on a cost recovery basis. Budgets and fees are required to be set for three years in advance, with over or under recoveries recovered in subsequent years.

Table 26 Other revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
SA Planning ($'000)	1.00	1.00	0.00	0.0%
Settlement Residue Auctions ($'000)	0.63	0.68	0.05	8.0%

2.19 Energy Consumers Australia (ECA)

Purpose of this function

To promote the long-term interests of energy customers, residential and small business customers

Revenue requirement and fees

AEMO is required to recover the funding for the ECA from market participants (i.e. pass through recovery). The budgeted ECA revenue requirement to be recovered in 2021-22 is $8.6m (2020-21: $8.3m). The increase is due to an increase in administrative costs of 4.2% and deficit recovery.

The electricity ECA fee remains unchanged at $0.01185 per connection point per week in 2021-22.

The gas ECA fee is $0.03861 per customer supply point per month in 2021-22 (13% increase). The fee increase is largely due to recovery of the 2020-21 deficit.

Table 27 ECA revenue requirement and fees

	Budget 2020-21	Budget 2021-22	Variance	Variance
Electricity				
Revenue Requirement	6.34	**6.43**	0.08	1.3%
Electricity FRC - Connection Points	10.36	**10.49**	0.12	1.2%
Electricity ($/connection point for small customers per week)	0.01185	0.01185	0.00000	0.0%
Gas				
Revenue Requirement	1.95	**2.19**	0.23	11.8%
MIRN's Basic Meters - Total (Millions)	4.75	**4.73**	-0.02	-0.4%
Gas ($/customer supply point per month)	0.03429	0.03861	0.00432	12.6%

Appendix A.

A1.1 Consolidated Profit and Loss

	AEMO (excl. Vic TNSP)			Victorian TNSP			AEMO		
	Budget 2020-21 $'m	Budget 2021-22 $'m	Variance $'m	Budget 2020-21 $'m	Budget 2021-22 $'m	Variance $'m	Budget 2020-21 $'m	Budget 2021-22 $'m	Variance $'m
REVENUE									
Fees and Tariffs	205.8	255.0	49.2	-	-	-	205.8	255.0	49.2
TUoS Income	-	-	-	591.5	603.0	11.5	591.5	603.0	11.5
PCF Fees	1.0	1.0	-	-	-	-	1.0	1.0	-
Settlement Residue	-	(0.0)	(0.0)	52.0	43.5	(8.6)	52.0	43.4	(8.6)
Other Revenue	13.4	19.5	6.1	60.7	58.4	(2.2)	74.1	77.9	3.9
TOTAL REVENUE	**220.2**	**275.5**	**55.3**	**704.2**	**704.9**	**0.7**	**924.4**	**980.4**	**56.0**
NETWORK CHARGES	-	-	-	(669.9)	(678.7)	(8.8)	(669.9)	(678.7)	(8.8)
NET REVENUE	**220.2**	**275.5**	**55.3**	**34.3**	**26.2**	**(8.1)**	**254.5**	**301.7**	**47.2**
OPERATING EXPENDITURE									
Total Labour	152.3	155.6	3.3	10.4	12.7	2.3	-	168.3	168.3
Consulting	12.9	10.8	(2.1)	11.6	10.2	(1.4)	24.6	21.1	(3.5)
Fees-Agency, Licence and Audit	2.1	2.0	(0.1)	-	-	-	2.1	2.0	(0.1)
IT & Telecommunications	33.3	47.3	14.1	0.0	0.0	(0.0)	33.3	47.4	14.1
Occupancy	8.2	7.7	(0.6)	-	-	-	8.2	7.7	(0.6)
Training & Recruitment	4.1	3.5	(0.7)	0.1	0.1	(0.1)	4.2	3.5	(0.7)
Travel & Accommodation	2.4	1.9	(0.5)	0.1	0.0	(0.0)	2.5	1.9	(0.6)
Other Expenses	8.8	10.2	1.4	0.0	0.0	(0.0)	8.8	10.3	1.4
Depreciation and Amortisation	28.4	43.9	15.4	0.0	0.0	(0.0)	28.5	43.9	15.4
Financing Costs	1.4	2.1	0.7	-	-	-	1.4	2.1	0.7
OPERATING EXPENDITURE (excluding external recoverable	**254.0**	**285.0**	**31.0**	**22.3**	**23.1**	**0.8**	**113.6**	**308.1**	**194.5**
External Recoverable Consultancy	1.7	3.6	1.9	1.3	1.9	0.6	3.0	5.5	2.5
Corporate Recovery (TNSP)	(7.5)	(10.7)	(3.2)	7.5	10.7	3.2	(0.0)	0.0	0.0
TOTAL OPERATING EXPENDITURE	**248.1**	**277.9**	**29.8**	**31.1**	**35.7**	**4.6**	**116.6**	**313.6**	**197.0**
ANNUAL SURPLUS / (DEFICIT)	**(28.0)**	**(2.4)**	**25.6**	**3.2**	**(9.5)**	**(12.7)**	**137.9**	**(11.9)**	**(149.8)**
Transfers to Reserves	(1.4)	(1.0)	0.4	-	-	-	(1.4)	(1.0)	0.4
Brought Forward Surplus	(33.0)	(53.6)	(20.6)	(1.4)	13.0	14.4	(34.3)	(40.6)	(6.3)
ACCUMULATED SURPLUS / (DEFICIT)	**(62.3)**	**(57.0)**	**5.3**	**1.8**	**3.5**	**1.7**	**102.2**	**(53.5)**	**(155.7)**

Appendix B. Fee schedules

B1.1 Fee schedule of electricity functions

Table 28 Budgeted total revenue requirement by function

Function	Budget 2021-22 $'000	Rate	Paying Participants
NEM			
General Fees (unallocated)	31,040	$0.17700/MWh of customer load	Market Customers
Allocated Fees			
Market Customers	39,110	$0.22302/MWh of customer load	Market Customers
Wholesale Participants	33,316	Daily rate calculated on 2020 capacity/energy basis	Wholesale Participants
NEM Revenue Requirement	**103,466**		
Participant Compensation Fund	1,000	Daily rate calculated on capacity/ energy basis	Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers
Registration fees	2,700		Participants that intend to register
Other	18,217		Dependent on service provided
Project developer		$6,365 per assessment per facility	Project developers
NEMDE queue		$15,450 per application	Registered participants
TOTAL NEM	**125,383**		
FRC ELECTRICITY			
FRC operations	14,173	$0.02592 per connection point per week	Market Customers with a Retail Licence
Other		$875 per book build application	Voluntary Book Build Participant Accreditation Fee
TOTAL FRC ELECTRICITY	14,173		
National Transmission Planner	22,965		Transmission Network Service Providers
Energy Consumers Australia	6,425	$0.01185/connection point for small customers/week	Market Customers
Additional Participant ID		$5,665 per additional participant ID	Existing Participants
IT UPGRADE AND 5MS/GS COMPLIANCE			
Market Customers	21,614	$0.12325/MWh of customer load	Market Customers
Wholesale Participants	3,230	Daily rate calculated on 2020 capacity/energy basis	Wholesale Participants
Total IT upgrade and 5MS/GS compliance	**24,844**		

Function	Budget 2021-22 $'000	Rate	Paying Participants
DER			
Market Customers	4,599	$0.02623/MWh of customer load	Market Customers
Wholesale Participants	1,150	Daily rate calculated on 2020 capacity/energy basis	Wholesale Participants
Total DER	5,749		
WA WHOLESALE ELECTRICITY MARKET			
WEM Market Operator fee	13,125	$0.380/MWh	WA Market Customers and Generators
WEM System Management fee	17,706	$0.514/MWh	WA Market Customers and Generators
WA WEM Revenue Requirement	30,831		
WA Economic Regulatory Authority fee	6,733	$0.195/MWh	WA Market Customers and Generators
Energy Policy WA Coordinator Fee	2,570	$0.075/MWh	WA Market Customers and Generators

Table 29 Fee schedule of new NEM registrations

Application type	2021-22 $
Registration as Scheduled Market Generator [A]	24,401
Registration as Semi-Scheduled Market Generator	32,888
Registration as Non-Scheduled Market Generator	21,218
Registration as Scheduled Non-Market Generator	18,035
Registration as Semi-Scheduled Non-Market Generator	27,583
Registration as Non-Scheduled Non-Market Generator	14,853
Transfer of Registration	11,670
Registration as Market Ancillary Service Provider	16,974
Registration as Market Customer	11,670
Registration as Market Small Generation Aggregator	11,670
Registration as Network Service Provider	10,609
Registration as Metering Co-ordinator (MC) [B]	11,670
Registration as Trader	14,853
Registration as Reallocator	13,792
Registration as an Intending Participant	6,365
Classification of a Dedicated Connection Asset [F]	5,305
Exemption from registration	6,365

Application type	2021-22 $
Frequency Control Ancillary Services	
Classification of generating units as frequency control ancillary services (FCAS) generating units [B]	10,609
Classification of load as frequency control ancillary services load – new ancillary services or classify load in a new region [C]	10,609
Amendment of the relevant plant associated with its existing load classification, and/or aggregating further load to its existing load classification for frequency control ancillary services purposes	2,122
Wholesale Demand Response	
Registration as Demand Response Service Provider	16,974
Classification of load as wholesale demand response unit – new wholesale demand response unit or classify load in a new region or load forecasting area [D, E]	10,609
Amendment of the relevant plant associated with its existing load classification, and/or aggregating further load to its existing load classification for wholesale demand response unit	2,122
Aggregation of load classified as wholesale demand response unit	2,122
Disbursement charges	
Disbursement Charge – Additional Energy Conversion Model – Semi Scheduled Market Generator	5,305
Disbursement Charge – Additional Energy Conversion Model – Non-Scheduled Market Generator	2,652

A. Each category of Generator in this table includes applications made by persons intending to act as intermediaries.
B. This fee is additional to the fee required to register as a Generator.
C. This fee is additional to the fee required to register as a Market Customer or Market Ancillary Service Provider or Demand Response Service Provider.
D. This fee is additional to the fee required to register as a Demand Response Service Provider.
E. This fee does not include aggregation of load.
F. This fee is no longer applicable starting from 22 July 2021.
Note: Fees relating to Demand Response commence upon opening for registration 24 June 2021.

Table 30 Fee schedule of new WA WEM registrations

Application type	2021-22 $
Rule Participant Registration Application Fee	2,400
Facility Registration Application Fee	4,400
Facility Transfer Application Fee	2,400
Conditional Certification of Reserved Capacity	1,199
Resubmission - Application for Early Certified Reserved Capacity	10,991
Consumption Deviation Application Reassessment Application Fee for Non-Temperature Dependent Loads and for Relevant Demand (Clause 4.26.2CC and 4.28.9B of the WEM Rules)	530

Note: Rule Participant De-registration and Facility De-registration will remain at zero.

Table 31 Fee schedule of new Power of Choice accreditations

Application type	2021-22 $
Initial Deposit – Embedded Network Manager	2,000

Application type	2021-22 $
Initial Deposit – Metering Data Providers	5,000
Initial Deposit – Metering Providers	5,000
Incremental charge rate per hour	Per Table 39

A1.2 Fee schedule of gas functions

Table 32 Gas fee by function

Function	Rate 2021-22	Basis
Vic Declared Wholesale Gas Market		
Energy Tariff	0.09938	$/GJ withdrawn
Distribution Meter	1.5647	$/day per meter
PCF	Nil	$/GJ withdrawn
VIC Gas FRC	0.05965	$ per customer supply point/ mth
QLD Gas FRC	0.26374	$ per customer supply point/ mth
SA Gas FRC	0.20341	$ per customer supply point/ mth
NSW/ ACT Gas FRC	0.13773	$ per customer supply point/ mth
WA Gas FRC	0.11974	$ per customer supply point/ mth
Annual fee – members	20,849	per annum
Annual fee – associate members*	4,066	per annum
STTM		
Activity Fee	0.03762	$/GJ withdrawn
PCF Fee – Syd	Nil	$/GJ withdrawn per hub per ABN
PCF Fee – Adel	Nil	$/GJ withdrawn per hub per ABN
PCF Fee – Bris	Nil	$/GJ withdrawn per hub per ABN
Energy Consumers Australia	0.03861	$ per customer supply point/ mth
Gas Statement of Opportunities		
Producer fee	0.00030871	$/GJ produced
Retailer fee	0.02669	$ per customer supply point/ mth
Gas Supply Hub		
Fixed Fee – Trading Participants	12,000	$ per licence per annum
Fixed Fee – Trading Participants	12,000	$ per additional licence per annum
Fixed Fee – Reallocation participants	9,000	$ per licence per annum

Function	Rate 2021-22	Basis
Fixed Fee – Viewing participants	3,600	$ per licence per annum
Variable Fee – Daily product fee	0.03	$/GJ
Variable Fee – Weekly product fee	0.02	$/GJ
Variable Fee – Monthly product fee	0.01	$/GJ
Gas Trading Platform*		
Fixed Fee – commodity and capacity	12,000	$ per licence per annum
Fixed Fee – capacity only	7,000	$ per licence per annum
Variable transportation fee	0.008	$/GJ Daily/Weekly/Monthly
Variable compression fee	0.008	$/GJ Daily/Weekly/Monthly
Day Ahead Auction*		
Other transportation fee	0.036	$/GJ
Compression fee	0.028	$/GJ
Gas Bulletin Board		
Producers	0.00049	$/GJ produced
Wholesale market participants	0.00249	$/GJ withdrawn
WA Gas Services Information	1,752	$'000
WA Economic Regulatory Authority revenue requirement	75	$'000
WA Energy Policy WA Coordinator revenue requirement	160	$'000
Additional Participant ID	5,665	$ per additional participant ID

Note: the variable fee for CTP and DAA is including a fee of $0.00318 relating to OTS code panel.

Table 33 Fee schedule of new gas registrations

Market	Budget 2021-22	Basis
Victoria Retail Gas		
Market Participant - Retailer	20,157	$ per registration per registrable capacity
Market Participant - Other	20,157	$ per registration per registrable capacity
QLD Retail Gas		
Retailer	18,035	$ per registration per registrable capacity
Self-Contracting User	18,035	$ per registration per registrable capacity
SA Retail Gas		
Retailer	16,974	$ per registration per registrable capacity
Self-Contracting User	16,974	$ per registration per registrable capacity
NSW Retail Gas		
Retailer	20,157	$ per registration per registrable capacity
Self-Contracting User	20,357	$ per registration per registrable capacity
WA Retail Gas		
WA Retail Gas - Member	13,435	$ per member
WA Retail Gas - associate member	2,686	$ per associate member
Victoria Wholesale Gas		
Market Participant - Retailer	20,570	$ per registration per registrable capacity
Market Participant - Trader	20,570	$ per registration per registrable capacity
Market Participant - Distribution Customer	19,970	$ per registration per registrable capacity
Short Tern Trading Market		
STTM User (BRI, ADL, SYD hubs)	20,870	$ per registration per registrable capacity
STTM Shipper (BRI, ADL, SYD hubs)	20,870	$ per registration per registrable capacity
STTM Allocation Agent	16,970	$ per registration per registrable capacity
STTM Pipeline Operator	36,470	$ per registration per registrable capacity
STTM Distributor	36,170	$ per registration per registrable capacity
STTM Storage Facility Operator	36,470	$ per registration per registrable capacity
STTM Production Facility Operator	36,470	$ per registration per registrable capacity
Pipeline Capacity		
Part 24 Facility Operator	15,914	$ per registration per registrable capacity
Day ahead auction – Auction Participant	15,914	$ per registration per registrable capacity
Gas Bulletin Board		
BB allocation agents	15,914	$ per registration

Market	Budget 2021-22	Basis
BB transportation facility user	11,670	$ per registration
BB capacity transaction reporting agents	11,670	$ per registration

A1.3 Quoted Registration fees for registerable capacity

Table 34 Quoted registration fees for registerable capacity

Market
DWGM
Market Participant - producer
Market Participant - Transmission customer
Market Participant - Storage Provider
Participant - Declared transmission system service provider
Participant - Interconnected transmission pipeline service provider
Participant - Distributor
Participant - Producer
Participant - Storage provider
Participant - Transmission Customer
Retail - NSW/ACT
Network Operator
Retail - Qld
Distributor
Retail - SA
Network operator
Network operator - Mildura region
Transmission System operator
Retail - Vic
Distributor
Transmission System Service Provider

A1.4 AEMO charge-out rates

Table 35 AEMO charge-out rates

Market	2021-22	Basis
Senior Leadership	500	$ per hour
Manager/ Specialist	420	$ per hour
Principal	335	$ per hour
Senior	295	$ per hour
Analyst/ Engineer	275	$ per hour
Officer/ Intern	235	$ per hour

Symbols and abbreviations

Term	Definition
5MS	5 Minutes Settlement
CTP	Capacity Trading Platform
DAA	Day Ahead Auction
DER	Distributed Energy Resource
DWGM	Declared Wholesale Gas Market
ERA	Economic Regulation Authority
ESOO	Electricity Statement of Opportunities
FRC	Full Retail Contestability
GBB	Gas Bulletin Board
GJ	Gigajoule
GSOO	Gas Statement of Opportunities
TJ	Terajoule
TNSP	Transmission Network Services Provider